SCE&G®

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March 5, 2019

VIA ELECTRONIC FILING

The Honorable Jocelyn G. Boyd
Chief Clerk/Administrator
Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, South Carolina 29210

RE: Annual Review of Base Rates for Fuel Costs of South Carolina Electric & Gas Company
Docket No. 2019-2-E

Dear Ms. Boyd:

Enclosed for filing on behalf of South Carolina Electric & Gas Company ("SCE&G") in the above-captioned docket is the direct testimony, exhibit and corrected Exhibit No. __(MWT-2) to the testimony of Matthew W. Tanner, Ph.D. Please be advised that the only change is to Exhibit No. __(MWT-2) and those corrections are as follows:

- Footnote 4 was revised to clarify that VACAR is a reserve sharing arrangement, not a balancing authority;
- Table 11 on page 24 of the exhibit was replaced with a corrected version; and
- The number of hours with insufficient reserves in Solar Case 2 on page 25 of the exhibit was revised from 201 to 196.

By copy of this letter, we are serving the parties of record with a copy of SCE&G's direct testimony, exhibit and corrected exhibit and attach a certificate of service to that effect.

If you have any questions, please advise.

Very truly yours,

Matthew W. Gissendanner

MWG/kms
Enclosures

cc: Jenny R. Pittman, Esquire
Dawn Hipp
Jeffrey M. Nelson, Esquire
Scott Elliott, Esquire
Alexander G. Shissias, Esquire
Richard L. Whitt, Esquire
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Lauren J. Bowen, Esquire
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(all via electronic mail only w/enclosures)
Becky Dover, Esquire
Carri Grube-Lybarker, Esquire
(both via electronic mail and U.S. First Class Mail w/enclosures)

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2019-2-E

IN RE:

Annual Review of Base Rates for Fuel Costs of South Carolina Electric & Gas Company	)	**CERTIFICATE OF SERVICE**

This is the certify that I have caused to be served this day one copy of South Carolina Electric & Gas Company's **direct testimony, exhibit and corrected exhibit of Mathew W. Tanner, Ph.D.** to the persons named below at the addresses set forth and in the manner described:

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Karen M. Scruggs

Karen M. Scruggs

Cayce, South Carolina

This 5th day of March 2019

DIRECT TESTIMONY OF

MATTHEW W. TANNER, Ph.D.

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2019-2-E

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INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Matthew W. Tanner. I have been employed by Navigant Consulting Inc. ("Navigant") since 2012, where I currently am a Director in the company's Energy Practice. My business address is 1200 19th St. NW, Suite 700, Washington, DC 20036.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND EXPERIENCE.

A. After graduating from Princeton University in 2004 with a Bachelor of Science in Engineering degree in Operations Research and Financial Engineering, I earned a Ph.D. in Industrial Engineering from Texas A&M University in 2009. I have over 10 years' experience in power systems modeling, economic analysis, utility resource planning, and Monte-Carlo simulation, which is a method to test a large number of random scenarios to evaluate the risk of an event occurring. My experience also includes evaluation of conventional and variable energy resources across North America and internationally, and the impact of these sources on electric reliability and cost of supply. A copy of my curriculum vitae listing my professional credentials and experience is attached as Exhibit No. ___ (MWT-1).

At Navigant, I lead our Wholesale Energy Markets group within our Energy & Capital Markets offering. I am responsible for advising utilities, state regulatory commissions, Independent System Operators ("ISOs"), developers, and other market participants on resource planning and strategy under uncertainty. I also have led and supported multiple projects helping utilities and ISOs understand the challenges and changing requirements for power system resources as variable energy resource penetration increases. Navigant regularly consults for electric municipal and cooperative utilities, in addition to state and federal agencies. As a matter of practice, Navigant is committed to maintaining an independent and unbiased approach to its engagements.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS BEFORE REGULATORY COMMISSIONS?

A. Yes. Although I have not previously testified before the Public Service Commission of South Carolina ("Commission"), I have testified as an expert witness before regulatory commissions in other states on topics including variable energy resource integration and load variability.

PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide background and discuss the findings and conclusions contained in the February 2019 Navigant study titled "Cost of Variable Integration" (the "Study") that was prepared on behalf of South Carolina Electric & Gas Company ("SCE&G" or the "Company"). A copy of the Study is attached to my testimony as Exhibit No. __ (MWT-2).

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. My testimony is organized as follows:

- First, I provide background on the key concepts and definitions that are useful to understanding the operating challenges that variable generation causes for utilities and how mitigating those challenges adds costs.
- Next, I summarize the results of the Study.
- I then explain the methodology Navigant used to develop the estimates of variable generation uncertainty, the analysis of the additional required reserves, and the forecast of the additional system cost from maintaining these reserves.
- Finally, I explain in greater detail the results of the Study and how Navigant developed the conclusions.

VARIABLE INTEGRATION COST STUDY BACKGROUND

Q. ARE THERE CERTAIN TERMS AND CONCEPTS THAT ARE USEFUL TO UNDERSTAND THE OPERATING CHALLENGES AND COSTS FOR INTEGRATING VARIABLE GENERATION ON THE SCE&G SYSTEM?

A. Yes. As part of my testimony, I use certain terms and concepts based upon the below descriptions and definitions:

- "Operating Reserves" means the capability of the electric system to quickly increase generation either by turning on quick-start electric generating units or ramping up the generating output of units that are currently online but not operating at full capacity. Available operating reserves are calculated in terms of how much additional generation is available in a given period of time. Operating reserves are needed by an electric system in order to respond to unexpected drops in generation or unexpected increases in load.
- "Variable Integration Cost" is the increase in costs to an electric system as a result of the need to react to unexpected changes in renewable generation.
- "Renewable Forecast Error" is the variance between the planned renewable generation and the actual renewable generation.
- "Plant Cycling" is the act of turning an electric generating plant on and off in response to the need to meet load.

- "Quick-start Resource" is an electric generating plant that can turn on quickly allowing it to provide operating reserves even when offline.
- "Ramp Up/Down" is the act of increasing or decreasing generation at an electric generating plant.
- "Production Cost Model" is a class of energy system models designed to simulate detailed system operation and costs over time.

Q. WHAT IS THE SCOPE AND PURPOSE OF THE STUDY?

A. Navigant conducted the Study in order to estimate the impacts that solar installations will have on SCE&G's system operations and to determine the resulting incremental costs. The Study evaluated the Variable Integration Costs for three different scenarios of solar generation installed on the system. These scenario assumptions were developed to generally correspond to the potential nameplate facility rating of solar facilities interconnected with or to be interconnected with the Company's system, as described by Company Witness Eric Bell.[1] The specifics of the Study scenarios are shown in Table 1 below:

[1] As discussed later in my direct testimony, the baseline scenario is conservative as more solar generation than assumed is already installed on the SCE&G system by December 31, 2018. In addition, based on the amount of additional utility-scale solar generation under construction and under contract with the Company, the amount of additional utility-scale solar generation SCE&G anticipates will be interconnected with its system by the end of 2019 and 2020 exceed the estimates used for analyzing Solar Case 1 and Solar Case 2.

Table 1. Assumed Solar Generation on SCE&G System

Solar	**Maximum Nameplate Facility Rating (MW)**				
	2019	2020	2021	2025	2030
Utility - Baseline	**336**	**336**	**340**	**363**	**404**
Utility - Solar Case 1	**637**	**637**	**641**	**664**	**705**
Utility - Solar Case 2		**1,044**	**1,048**	**1,071**	**1,112**

Q. WHAT ANALYSES DID NAVIGANT UNDERTAKE IN PERFORMING THE STUDY?

A. The initial analysis focused on establishing a benchmark for Navigant's PROMOD® production cost model that reflected SCE&G's actual system operating experience and the Company's own internal planning. The purpose of this initial analysis was to provide an appropriate and reasonable baseline for the Variable Integration Cost estimate.

Next, Navigant conducted a solar uncertainty analysis, which estimated the forecast error for solar generation installed on the system. The purpose of this analysis was to determine the amount of operating reserves that must be maintained by the Company in order to ensure that SCE&G can reliably respond and meet system needs if actual generation is less than forecasted.

The analysis then considered the challenges the Company would experience if additional reserves are not added to the system. The Study provides examples and analysis of time periods when SCE&G operators would experience insufficient amounts of resources that would be needed to maintain system reliability.

Finally, the Study estimated the Company's cost to maintain additional reserves necessary to integrate the variable energy generated by solar facilities. It also includes an analysis of the potential and cost to add new resources to the system as an alternative mitigation option.

Q. HOW DOES THE VARIABILITY OF SOLAR GENERATION CAUSE ADDITIONAL OPERATING ISSUES FOR SCE&G?

A. The amount of solar energy that can be generated is significantly impacted by and dependent on the weather. Therefore, there is inherent uncertainty in how much electricity is actually generated by solar generating facilities. In order to operate a safe and reliable electric system, SCE&G operators must closely match generation and load at all times. If there is forecast error and less solar generation than expected, then SCE&G must have the ability to ramp up other generating facilities to replace the lost solar energy.

This ability to ramp up generation over a given time period is a component of operating reserves. Operating reserves are maintained either by keeping generators online but operating at less than their full capacity or by maintaining quick-start generating resources. SCE&G operators also have to balance the need to meet its load and to maintain sufficient operating reserves with the goal of operating its system at a reasonable minimum cost.

Q. HOW DOES SOLAR GENERATION RESULT IN ADDITIONAL COST TO SCE&G'S SYSTEM?

A. When solar generation is added to the system, SCE&G's operators must maintain additional operating reserves in order to ensure that if less solar generates than expected, the system can respond. This adds cost by one of two mechanisms:

- The system operation must be changed from its previous minimum cost schedule and operate less efficiently so that additional operating reserves are available to meet unanticipated changes in solar generation, thereby increasing variable operating costs.
- The Company must add new resources to its system to maintain sufficient operating reserves to meet these needs, resulting in additional capital cost expenditures.

Q. HOW ARE THESE COSTS DIFFERENT FROM THOSE ESTIMATED IN THE PR-1 AND PR-2 AVOIDED COST CALCULATIONS?

A. The PR-1 and PR-2 avoided cost calculations described in Company Witness James Neely's testimony reflect the change in SCE&G's costs from adding solar to the system as if the solar generation forecast was 100% reliable. By comparison, the Navigant Study evaluates the additional integration costs incurred by SCE&G to ensure the Company can reliably operate its system considering the potential for solar forecast error. In this Study, Navigant was careful to design the Study methodology and analysis to be consistent with the PR-1 and PR-2 avoided cost methodology and prevent double counting of SCE&G costs.

Q. HAVE OTHER UTILITIES ESTIMATED THE INTEGRATION COST FOR VARIABLE GENERATION?

A. Yes. In recent years, other utilities including Duke Energy Progress, Duke Energy Carolinas, PacifiCorp, and Idaho Power, have estimated variable integration costs on their systems. Additionally, ISOs such as NYISO and PJM have conducted variable integration studies to understand what operation impacts (such as additional ancillary service procurement) might be needed to ensure reliability given increasing levels of variable generation on the system.

VARIABLE INTEGRATION COST STUDY RESULTS SUMMARY

Q. WHAT ARE THE STUDY'S FINDINGS AND CONCLUSIONS?

A. Navigant's findings and conclusions can be summarized as follows:

- The solar generation being added to SCE&G's system is a variable resource and adds uncertainty to the generation needed from the rest of the system.
- SCE&G needs to maintain additional operating reserves in order to ensure that load and current reserve obligations are met. Without these additional operating reserves, there will be an unacceptable number of hours where SCE&G will face a shortfall in its available operating reserves.
- The levelized cost of maintaining additional operating reserves is $3.96/MWh for Solar Case 2.
- Adding additional resources such as battery storage or quick-start gas combustion turbines will not reduce integration costs for solar due to the additional capital cost currently required for these facilities.

VARIABLE INTEGRATION COST STUDY METHODOLOGY

Q. WHAT APPROACH DID NAVIGANT FOLLOW TO DERIVE ITS FINDINGS AND CONCLUSIONS?

A. A detailed description of the Study assumptions and methodology are provided in the report attached to my testimony as Exhibit No. ___ (MWT-2). The key aspects of the approach are summarized as follows:

1. Navigant benchmarked its PROMOD® production cost model to SCE&G's system using information provided by the Company in

order to provide a baseline for the analysis. The baseline for each solar penetration scenario reflects system operation without requiring any additional reserves to be maintained.

2. The solar forecast uncertainty was estimated by comparing solar forecasts with actual solar generation from the National Renewable Energy Lab's solar integration dataset. Solar forecast uncertainty was calculated as the variance of the 15-minute average of actual solar generation from the 4 hour-ahead forecast. Using this information, Navigant calculated the probability of how much less than expected solar facilities actually generate, which varies depending on the forecasted level of solar generation.

3. Navigant forecasted the challenges to SCE&G system operation as a result of this variability in solar generation by determining the hours in which system operators would be unable to maintain the current required level of reserves if solar missed its forecast by the amount estimated in step 2 described above. The hours demonstrate that SCE&G needs to maintain additional reserves to safely and reliably operate its electric system in light of the variability in solar generation.

4. The level of additional reserves that SCE&G needs to maintain was calculated as the maximum amount per day that solar could underproduce the forecasted amount.

5. Using PROMOD®, Navigant simulated system operation and production costs with additional reserves maintained by SCE&G. The difference in production costs is the integration costs attributable to the solar generation. Navigant then levelized the solar generation integration costs to create a $/MWh value.
6. Navigant evaluated the effect of adding battery storage and gas combustion turbines to SCE&G's system as alternative mitigation options in order to determine whether adding these types of resources could reduce the Company's system costs instead of simply maintaining operating reserves based on SCE&G's current resource mix.

Q. PLEASE DESCRIBE PROMOD®.

A. PROMOD® is a widely-used industry-standard production cost model developed and licensed by ABB Ventyx. The PROMOD® modeling software is programmed to develop a low-cost energy supply solution for system load while also providing the required level of operating reserves and regulation. PROMOD® then simulates the balancing of resources to load on an hourly basis in order to generate a time-series optimized portfolio or unit commitment and dispatch optimization. In this manner, PROMOD® is able to simulate varying levels of resources, loads, or reserve requirements and to examine the cost impact of each change.

As part of this analysis, PROMOD® also considers physical constraints of generation and fuel, emissions constraints, and reserve requirements. The software takes into account the operational advantages and disadvantages of each generation type and quantifies the cost impact of forcing operation away from the most economical way in which to operate the system.

Q. WHAT ASSUMPTIONS DID NAVIGANT USE REGARDING THE AMOUNT OF SOLAR GENERATION ON SCE&G'S SYSTEM?

A. In conducting the Study, Navigant considered three different scenarios which represent potential amounts of solar penetration that, at the time the Study was commissioned and as further described in the direct testimony of Company Witness Eric Bell, SCE&G expected it would experience on its system over the next few years.

The Baseline scenario is based on an estimate of the level of solar generation expected to be installed on the Company's system by the end of 2018. The Solar Case 1 is based on the solar facilities expected under the Baseline scenario as well as solar facilities currently under construction and anticipated to come online by the end of 2019. The Solar Case 2 is based on the amount of solar expected under the Baseline scenario, Solar Case 1, and the amount of solar generation that currently is not under construction but is expected to be added to SCE&G's system by the end of 2020 pursuant to signed power purchase agreements.

Q. HOW DO THE ASSUMPTIONS USED BY NAVIGANT IN CONDUCTING THE STUDY COMPARE TO SCE&G's ACTUAL EXPERIENCE?

A. SCE&G's actual and updated experience and forecasts reflect that the Company has and will have more solar interconnections than those reflected in the Study's assumptions. Specifically and as discussed by Company Witness Eric Bell, at the end of 2018, SCE&G had 345 MW (cumulative nameplate facility rating) of utility scale solar interconnected to its system, which already exceeds the Baseline scenario projections of 336 MW used in the Study. Likewise, SCE&G currently forecasts that, by the end of 2019, the Company will have 643 MW (cumulative nameplate facility rating) of utility scale solar interconnected with its system, as compared to the Solar Case 1 scenario projection of 637 MW. Finally, SCE&G currently forecasts that, by the end of 2020, approximately 1,050 MW (cumulative nameplate facility rating) of utility scale solar will be interconnected with its system as compared to the Solar Case 2 estimate of 1,044 MW used in the Study.

Q. HOW DOES THIS GREATER AMOUNT OF SOLAR GENERATION CURRENTLY INTERCONNECTED AND FORECASTED TO BE INTERCONNECTED WITH THE COMPANY'S SYSTEM IMPACT THE RESULTS OF THE STUDY?

A. As more solar generation is interconnected with the Company's system, SCE&G will experience an increasing amount of Variable Integration Costs. Accordingly, the Variable Integration Costs estimated in the Study are lower than SCE&G will actually experience based upon the amount of solar generation currently interconnected and expected to be interconnected with its system. Therefore, the Variable Integration Costs estimated in the Study are conservative.

Q. PLEASE DESCRIBE THE IMPACT OF GEOGRAPHIC DIVERSITY OF RENEWABLE RESOURCES AND THE IMPORTANCE OF INCLUDING IT IN THE STUDY.

A. The concept of geographic diversity recognizes that solar generation is not located in a single area, but in different places throughout a system. Since weather can vary significantly between locations, even within a relatively compact service territory, geographic diversity means that there is variability in how different solar installations can change their generation output at any given time.

It is critical to incorporate geographic diversity in an integration cost study because it has the effect of reducing the total amount of uncertainty facing SCE&G. Without considering geographic diversity, the estimated integration costs would be too high.

Q. WHAT LEVELS OF OPERATING RESERVES DID NAVIGANT STUDY FOR EACH OF THE SOLAR PENETRATION SCENARIOS AND WHY?

A. The analysis of solar uncertainty on the SCE&G system showed that the forecast error for solar 4 hours before operation is dependent upon the level of solar generation on the system. Table 2 below shows the relationship between the level of expected generation and the risk of less generation actually being available at the time of operation. The main result is that as the expected solar generation (as a percentage of installed solar nameplate facility rating) increases, the percentage of that generation which is at risk of not actually being available declines.

Table 2: Comparison of Expected Generation and Actual Generation

Expected Generation as % of Installed Solar Nameplate Facility Rating	Maximum Drop in Generation
< 40%	75%
40% - 50%	65%
50% - 55%	45%
> 55%	25%

When committing units, SCE&G needs to maintain sufficient reserves to be able to increase generation to replace solar generation that does not meet forecasted amounts. Table 3 below shows the level of reserves needed for the maximum daily solar generation in each month in each solar penetration scenario. The business-as-usual ("BAU") reserves are the reserves currently needed to satisfy VACAR requirements and to safely and reliably serve the load on the Company's system.

Table 3: Reserves Needed to Maintain Reliability

Year	BAU	Baseline	Solar Case 1	Solar Case 2
2019	240	347	421	420
2020	240	348	445	529
2021	240	349	447	579
2022	240	351	448	581
2023	240	352	450	582
2024	240	354	451	584
2025	240	356	453	586
2026	240	358	456	588
2027	240	360	458	590
2028	240	363	460	593
2029	240	365	463	595
2030	240	368	466	598
2031	240	371	469	601
2032	240	375	472	605

Because the solar forecast is not the same each day, Navigant then blended the results of the PROMOD® runs with the different levels of reserves to account for days in which less solar is forecasted than others. For example, the analysis calculated integration costs for Solar Case 2 using the following proportions of days in which these levels of reserves must be maintained:

- Solar Case 2 level of reserves is needed 38% of the days
- Solar Case 1 level of reserves is needed 51% of the days
- Baseline level of reserves is needed 12% of the days

Q. WILL UTILITY COSTS INCREASE AS A RESULT OF INTEGRATING SOLAR GENERATION ON AN ELECTRIC SYSTEM?

A. Yes. Solar integration will increase utility costs. For example, a utility's fuel costs can increase as units are required to operate at less than maximally efficient levels. Start-up costs also can increase due to the increased need to cycle generating units on and off more frequently. Variable maintenance costs can increase either when generating units with higher variable cost are dispatched to provide needed reserves or due to the additional stress that is placed on units that are ramping to follow the solar generation. Emissions costs also can increase if the generating units needed to provide reserves have higher emissions expenses. Finally, a utility's capital costs can increase if it is required to add new generating resources or if capital investments are made to increase the flexibility of existing generating units.

Q. DOES THE STUDY CONSIDER SYSTEM COSTS FOR SCENARIOS WITH DIFFERENT LEVELS OF OPERATING RESERVES?

A. Yes. The Study calculates operating reserve levels as the maximum daily potential forecast error of solar generation at each level of solar penetration. This maximum was fairly constant by month but varied day-to-day. For days in which solar generation is forecasted to be low, the level of reserves that the utility needs to maintain are less than the overall monthly maximum.

If the maximum operating reserve increases were assumed to be maintained every day, the estimate of integration costs would be too high. PROMOD® does not allow operating reserve levels to change day-to-day. Therefore, in order to incorporate the days with lower requirements, Navigant calculated the costs using varying levels of operating reserves and then blended those costs using weightings tied to the proportion of days with the appropriate level of solar uncertainty. This blending ensures that the study does not overestimate costs.

Q. HOW DID NAVIGANT ENSURE THAT THERE WAS NO DOUBLE COUNTING OF COSTS WITH THE RESULTS OF THIS STUDY AND THE PR-1 AND PR-2 AVOIDED COST STUDY?

A. The avoided costs for solar reflected in the PR-1 and PR-2 Rates included the following cost increases from solar penetration:

- Energy not Served – $0.682/MWh
- Reserves Deficit - $0.284/MWh
- Total (rounded) – $0.97/MWh

If SCE&G maintains additional reserves to integrate the solar generation, these costs would be reduced as a side effect. Conservatively, the Study assumed that 100% of these cost increases, or the rounded total of $0.97/MWh, is subtracted from the raw variable integration cost calculation so as not to potentially double count these costs.

Q. DOES THE STUDY CONSIDER THE POSSIBILITY OF CHANGING HOW THE COMPANY'S FAIRFIELD PUMPED STORAGE OPERATES IN ORDER TO INTEGRATE SOLAR GENERATION?

A. Yes. The PROMOD® representation of Fairfield Pumped Storage allows the model to change its operation to minimize overall system cost while meeting the requirements for solar integration. The pumped storage was allowed to both provide operating reserves and to smooth out the net load that must be met by SCE&G generation. Therefore, the presented variable integration costs are inclusive of the ability to change Fairfield Pumped Storage's operation.

VARIABLE INTEGRATION COST STUDY CONCLUSIONS

Q. BASED ON THE STUDY, WHAT IS THE INTEGRATION COST FOR VARIABLE GENERATION ON THE SCE&G SYSTEM?

A. The variable integration cost in Solar Case 2 is $3.96/MWh. This is net of the costs already presented in PR-1 and PR-2. Table 4 below shows the breakdown in these costs by category.

Table 4: Variable Integration Costs on SCE&G's System

	VOM	**Fuel**	**Emission**	**Start-up**	**Total**
Cost Difference NPV ($)	$13,941,615	$40,320,211	$48,760	$19,103,954	$73,242,219
Generation NPV (MWh)	18,495,510				
Levelized Cost ($/MWh)	$0.75	$2.18	$0.003	$1.03	$3.96
% of Total Cost	19%	55%	0.1%	26%	100%

Q. DOES THE SYSTEM COST CHANGE AS ADDITIONAL RESERVES ARE MAINTAINED?

A. Yes. In every solar penetration case, when more reserves are required on the system, the system cost and the levelized variable integration costs increase.

Q. HOW DOES THE VARIABLE INTEGRATION COST CHANGE AS ADDITIONAL SOLAR IS ADDED TO THE SYSTEM?

A. As shown in Table 5 below, the variable integration costs increase nearly linearly with the increase in solar generation across the three solar penetration scenarios. As a result, the levelized variable integration cost is relatively constant for all three scenarios.

Table 5: Variable Integration Costs With Increased Solar Generation

	Baseline	**SC1**	**SC2**
Cost Difference NPV (2020 $)	$21,441,812	$46,878,790	$73,242,219
Levelized Cost (2020 $/MWh)	$3.52	$4.04	$3.96

Q. IS IT POSSIBLE FOR SCE&G TO REDUCE ITS COSTS TO INTEGRATE VARIABLE GENERATION BY ADDING BATTERY STORAGE OR NEW COMBUSTION TURBINE (“CT”) GAS UNITS?

A. At this time, adding additional resources is not a cost-effective approach to lower the variable integration costs of the current and expected solar generation. The amount of 1-hour battery storage that can be added for the additional system costs of approximately $73.2 million is approximately 95 MW assuming future improvements in technology and cost declines through 2025. The amount of CT gas capacity that can be added is approximately 110 MW. Neither of these capacities is sufficient to provide the reserves needed to integrate the solar generation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

NAVIGANT

Matthew Tanner, PhD

Director

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Professional Summary

Matt is a director in Navigant's Energy and Capital Markets group. He supports market participants in understanding and planning for the changing dynamics of energy markets and the overall power industry. With over 10 years' experience in integrated resource planning, energy market strategy, and risk analysis, he focuses on developing and providing highly analytical and creative approaches for utilities, investors, independent power producers, and other market participants to evaluate emerging market opportunities and adapt their business models to the changing markets across North America.

Matt is an expert in helping clients understand the underlying drivers of Navigant's wholesale market forecasts as well as potential changes that can drive risk both on the upside and downside. For utility clients, Matt ensures that they understand their changing requirements and technology options to meet those requires. He supports them in ensuring that they can operate their systems reliably and at the lowest cost.

Areas of Expertise

- **Utility Strategy and Resource Planning.** Guides utilities throughout North America in their resource planning and developing their strategy in response to the changing power system. Specializes in developing novel approaches for utilities to evaluate emerging issues such as integration of variable energy resources, the economics of decarbonization, and business opportunities with new technologies and distributed energy resources.
- **Wholesale Market Forecasting and Business Strategy.** Leads and contributes to a wide variety of energy planning projects both at the wholesale and distribution level. Focuses on scenario analysis of asset value, wholesale power market price forecasting, benefit/cost analysis, and asset decision analysis for existing and emerging technologies. Has strong experience evaluating and developing business models for battery and bulk storage stacking applications in energy, ancillary services, and capacity.
- **Wholesale Market Design and Participation.** Strategic support of ISOs and system operators as they are developing, reforming, or determining whether to join organized energy markets. Works on the key challenges and opportunities that are arising due to zero marginal cost generation and the rising need and value of flexibility in the system.

NAVIGANT

Matthew Tanner, PhD

Director

Relevant Experience

Utility Strategy and Resource Planning

- Once-Through-Cooling Retirement Analysis, LADWP, 2017 - 2018. Leading the economic analysis of LADWP's strategy regarding retirement of its once-through-cooling units.
- IRP Support, FortisBC, 2016-2018. Supported FortisBC as an expert in IRP modelling and the Northwest US power market.
- Variable Generation Study, NorthWestern, 2017 – 2018. Led project to estimate increased needs for renewable integration support for NorthWestern with rising wind and solar penetration. Testified on results.
- IRP Support, SaskPower, 2016. Supporting SaskPower in redesigning its planning process including definitions of scenarios, resource options, and risk analysis.
- Development of Short-Term Asset Risk Model, J-Power, 2016. Led the effort and designed a short-term market forecasting model to support J-Power in understanding upcoming market risks.
- Monte-Carlo Analysis of Transmission Project Costs, Exelon, 2016. Developed a Monte-Carlo model that supported the response to an RFP by providing a simulated range of costs for a transmission project.
- Review of Resource Plan, Austin Energy, 2015. Project manager to review Austin Energy's resource plan and presented results to city council.
- Renewable Integration Analysis, LADWP, 2015. Task lead to evaluate the ability of LADWP to integrate high levels of renewable power into its system from a production cost planning framework.
- Evaluation of Best Practices Incorporating Distributed Energy Resources (DER) into IRP, DTE, 2015. Led project to survey utilities on best practices in incorporating DER and wrote report.
- Integrated Resource Planning Model, Northwest Power and Conservation Council, 2014-2015. Helped redevelop the RPM integrated resource planning model that the council uses in the Northwest.
- Developed Simulation of Power Plant Outages and Penalties Under Contract, TransCanada, 2015. Developed a Monte-Carlo simulation of unit outages and the implications for penalties under the plant PPA to support contract negotiations.

Wholesale Market Forecasting and Business Strategy

- Evaluation of Portfolio of Renewable Assets, John Hancock, 2018. Led the market forecasting for a portfolio of renewable assets including basis and congestion risk.

NAVIGANT

Matthew Tanner, PhD

Director

- Post-PPA Valuation of Assets in Ontario and Quebec, Enbridge, 2018. Led the estimation and valuation of renewable assets in Ontario and Quebec that are coming off of PPAs in the next 15 years.
- Economic Analysis of SOO Green Renewable Rail Project, SOO Green, 2017. Led the arbitrage analysis of a potential high voltage direct current transmission line from Iowa to Illinois.
- Economic Analysis of PJM Battery Project, SGEM, 2017. Led the forecasting regulation prices and valuation of a battery project in PJM.
- Economic Analysis of San Vicente Pumped Storage, San Diego Water Authority, 2016. For SDWA, led the modelling task to evaluate the economics of the pumped storage facility within the California ISO (CAISO) market.
- Ancillary Service Market Dynamics and Price Forecasting, E.ON, 2016. For E.ON. led project to develop a report explain A/S market prices and the key drivers.
- Pennsylvania-New Jersey-Maryland Interconnection (PJM) Hydro Transaction, PSP, 2015. Forecasted market value for a hydro asset and advised on market rules and changes in PJM to support a potential transaction.
- Renewable Power Transactions, Korean Electric Power (KEPCO), 2015. Supported KEPCO in valuating renewable plants in US and advised on impacts of market drivers and regulatory changes.
- Modelling of New York ISO (NYISO) Frequency Market Drivers, US Department of Energy, 2015. Reviewed and modelling the key market drivers for the NYISO frequency regulation to forecast prices.
- Analysis of Value of Fast Dispatch in Electric Reliability Council of Texas (ERCOT), Investor, 2015. Modelled dispatch of a fast-start resource in ERCOT operating in real-time market.

Wholesale Market Design and Participation

- Strategic Support of Market Renewal, Independent Electricity System Operator (IESO), 2017-2018. Project manager for Navigant's strategic supporting role for IESO's market renewal effort. Helping stakeholders understand cross-cutting issues and the needs of the changing power system.
- Market Renewal Workshops, IESO, 2016-2017. Created and presented a set of workshops to internal and external stakeholders to educate on market renewal.
- Analysis of Economic Impacts of RTO Membership, LADWP, 2016. Led economic analysis task to support LADWP to understand the impacts of potential RTO membership.
- Evaluation of Joint Economic Dispatch in Florida, 2016. Led the economic modelling of joint economic dispatch within the FRCC territory.

NAVIGANT

Matthew Tanner, PhD

Director

- Calculation of Default Emissions Factor, Ontario Ministry of Energy, 2016 - 2017. Modelled the marginal resources for markets exporting to Ontario and calculated the emissions factors that should be applied to be consistent with Ontario carbon policy.

Work History

Director, Navigant Consulting, Inc.
Operations Research Analyst, US Information Administration

Education

PhD, Industrial Engineering	Texas A&M University
BSE, Operations Research and Financial Engineering	Princeton University

Cost of Variable Integration

Prepared for South Carolina Electric & Gas Company

SCE&G is becoming

Dominion Energy®

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March 2019

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DISCLAIMER

NOTICE

This report was prepared by Navigant Consulting, Inc. (Navigant) for South Carolina Electric & Gas Company (SCE&G). The work presented in this report represents Navigant's professional judgment based on the information available at the time this report was prepared. Navigant is not responsible for the reader's use of, or reliance upon, the report, nor any decisions based on the report. NAVIGANT MAKES NO REPRESENTATIONS OR WARRANTIES, EXPRESSED OR IMPLIED. Readers of the report are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the report, or the data, information, findings and opinions contained in the report.

EXECUTIVE SUMMARY

This study was commissioned by SCE&G in order to estimate the impacts that solar installations will have on system operation and the resulting incremental costs. The study considers the variable integration costs for 3 different scenarios of solar generation installed on the system. Due to the variable nature of solar generation, SCE&G needs to ensure that there are sufficient reserves on the system to be able to meet load when less solar is generated than was forecasted. This study evaluates the uncertainty in the solar generation, the resulting reserve requirement for SCE&G, and the added operating costs from holding those reserves. The study also considers whether alternative mitigation options such as adding new battery storage or gas combustion turbine units can reduce this cost.

SCE&G's challenge is that the utility combines both a large proportion of inflexible baseload (coal and nuclear) generation with high penetration of solar installations. This causes operational challenges due to the limits of the baseload generation for ramping up or ramping down in response to solar generation.

Study Approach

For this analysis, Navigant first benchmarked its PROMOD model to SCE&G's system to create a baseline. Three solar penetration scenarios were then run to analyze the impacts that various levels of solar would have on the system. Each scenario included different amounts of solar and is described below.

- Baseline Scenario (Baseline)– 336 megawatts (MW) of solar generation interconnected with SCE&G's system by the end of 2018.[1]
- Solar Case 1 (SC1)– 637 MW of solar generation interconnected with SCE&G's system by the end of 2019.
- Solar Case 2 (SC2)– 1,044 MW of solar generation interconnected with SCE&G's system by the end of 2020.

The following methodology was used to evaluate the impacts of solar generation and the variable integration costs:

1. PROMOD production cost software was benchmarked to the existing SCE&G system to provide a baseline of system operation in each of the solar penetration scenarios.
2. Solar generation uncertainty and forecast error was estimated.
3. The additional reserves needed to integrate the solar generation was calculated.
4. PROMOD was used to calculate the production costs with additional reserves required and the resulting levelized variable integration costs.

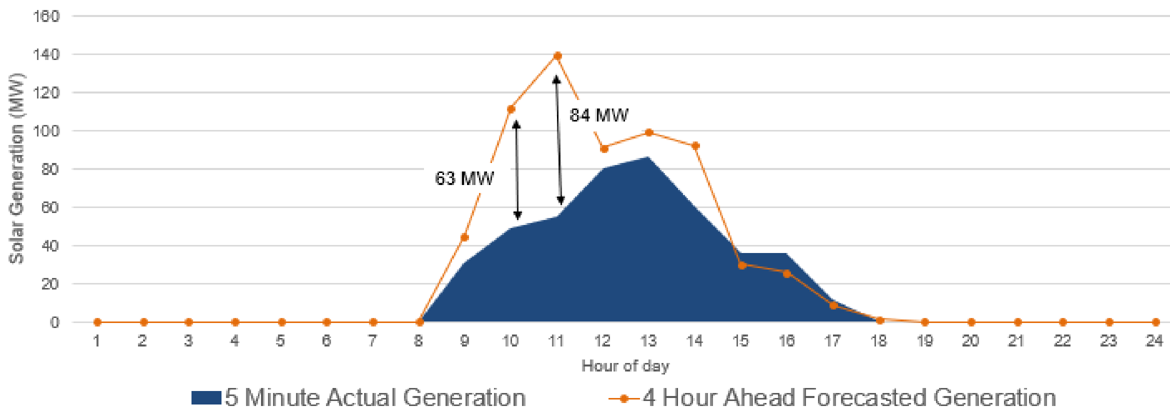
[1] This is a conservative case. Actual installations by the end of 2018 already exceed this amount.

5. Alternative mitigation options were evaluated.

Renewable Uncertainty and Need for Additional Reserves

SCE&G must operate the system differently in order to maintain reliability when solar generation increases. The following figure gives an example of how solar forecast error and uncertainty can cause actual generation to be less than forecasted generation. In this case, SCE&G must have the capability to ramp generation up to meet load when the solar generation is less than expected.

Figure 1. Solar Generation Variability Example



The following table shows the results of the analysis of the maximum expected drop in solar generation as it relates to the level of expected generation.

Table 1. Solar Forecast Uncertainty

Expected Generation as % of Installed Nameplate Facility Rating	Maximum Drop in Generation
< 40%	75%
40% - 50%	65%
50% - 55%	45%
> 55%	25%

The mechanism to ensure that SCE&G can meet load when solar generates less than forecast is to hold additional operating reserves with units that can either start up quickly or are operating at less than full load. The following table shows the operating reserves that SCE&G holds now as "Business as Usual" (BAU) and would have to hold in each solar case.

Table 2. Maximum Additional Reserves Needed

Year	BAU	Baseline	SC1	SC2
2019	240	347	421	420
2020	240	348	445	529
2021	240	349	447	579
2022	240	351	448	581
2023	240	352	450	582
2024	240	354	451	584
2025	240	356	453	586
2026	240	358	456	588
2027	240	360	458	590
2028	240	363	460	593
2029	240	365	463	595
2030	240	368	466	598
2031	240	371	469	601
2032	240	375	472	605

Conclusions

There are two broad mechanisms for SCE&G to ensure that there are sufficient reserves on the system:

1. Operate the existing system differently so that there are more operating reserves.
2. Procure quick-start resources such as battery storage or CT gas units that will be able to provide reserves even when offline.[2]

Holding reserves increases costs by causing less efficient units to operate more and by having units operate at less than full capacity. This increases variable operating and maintenance (VOM), fuel costs, emissions costs, and start up costs. The following table shows how the overall production costs change

[2] Note that there are methods for solar units to provide flexibility and ramping to the system. Although this may be a feasible alternative in the future, this possibility has not been considered in this analysis because SCE&G cannot implement it unilaterally but only with technological changes by the solar facility owners.

for SCE&G and how this leads to a 15 year (2020 -2034) levelized variable integration cost of $3.96/megawatt-hour (MWh).

Table 3. Breakdown of Incremental Costs in SC2

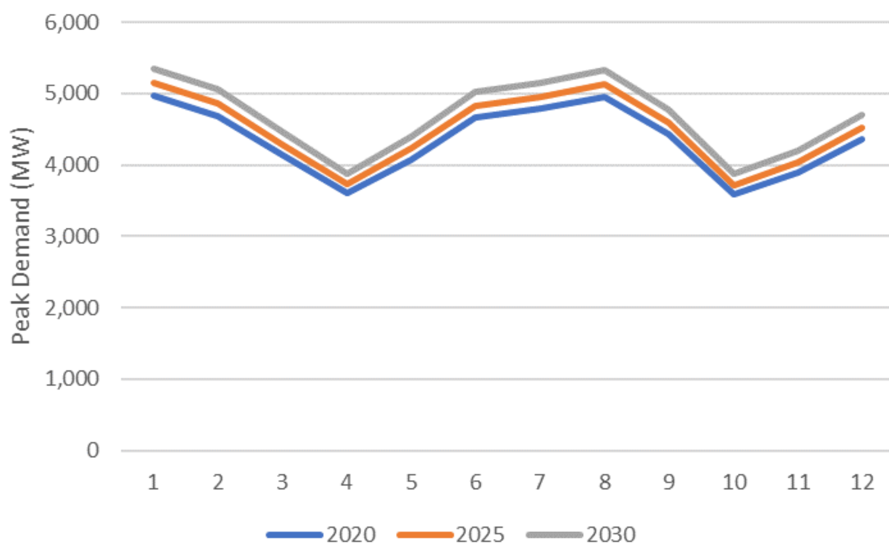
	VOM	Fuel	Emission	Start-up	Total
Cost Difference NPV ($)	$13,941,615	$40,320,211	$48,760	$19,103,954	$73,242,219
Generation NPV (MWh)			18,495,510		
Levelized Cost ($/MWh)	$0.75	$2.18	$0.003	$1.03	$3.96
% of Total Cost	19%	55%	0%	26%	100%

1. IMPACT OF SOLAR ON SCE&G OPERATION

1.1 The SCE&G Power System

SCE&G provides electric services for a large portion of South Carolina, with forecasted hourly demand typically ranging from approximately 2,000 to 5,000 MW, and forecasted monthly peak demand between approximately 3,500 and 5,000MW depending on the year and before accounting for demand-side resources. SCE&G experiences both winter and summer peaks, as shown in Figure 2, with the highest demand occurring during January and August. This trend is expected to remain consistent over time.

Figure 2. Monthly SCE&G Peak Demand[3]



SCE&G operators must ensure that both system load and operating reserves are met in all normal conditions. SCE&G is required to hold 200 MW of reserves at all times to meet their requirements within VACAR to be able to respond to the loss of the single-largest unit on the system.[4] An additional 40 MW of reserves are held for load-following. Due to the need for self-sufficiency, SCE&G must rely on its own generators to meet generation and reserves, and cannot rely on external sources.

Reserve requirements are met by operating the system in a manner to maintain the capability to increase generation quickly up to the level of reserves that are required. For example, many of SCE&G's combustion turbine (CT) units are able to start within 15 minutes. These units provide reserves even

[3] Not including demand-side resources.

[4] VACAR is a reserve sharing arrangement that SCE&G is a part of. Being part of VACAR helps SCE&G maintain sufficient contingency reserves in order to respond to the single largest contingency on the system without having to hold all of the reserve requirement. The 200 MW of reserves for SCE&G is its share of these contingency reserves..

when they are not operating. The combined cycle (CC) units require two hours or more to start if they are not operating. These units can only provide reserves if they are turned on and operating below their full capability (holding some capability in reserve). Operating units below full capacity is less efficient both economically and environmentally.

A summary of SCE&G's resources can be found in the table below; solar is not included as new resources are still being considered and would vary case to case for the scenarios run. SCE&G also has 100 MW of interruptible load that can be used to meet reserve requirements.

Table 4. Summary of SCE&G Resources

Technology	Name Plate Capacity (MW)	Avg. Ramp Rate (MW/hr)	Quick Start	Avg. Start Cost ($)
Combined Cycle	2,430	302	No	$17,101
CT Gas	389	76	Yes[1]	$0
ST Gas[2]	796	186	No	$3,466
ST Coal[2]	1,881	62	No	$10,317
Nuclear	650	480	No	$0
Hydro	239	239	No	$0
Pumped Storage	576	576	No	$0

1. *Urqhart CT Gas #4 is not capable of providing quick start reserves.*
2. *The Cope Steam Turbine plant runs on natural gas during the summer and on coal during winter, due to fuel availability.*

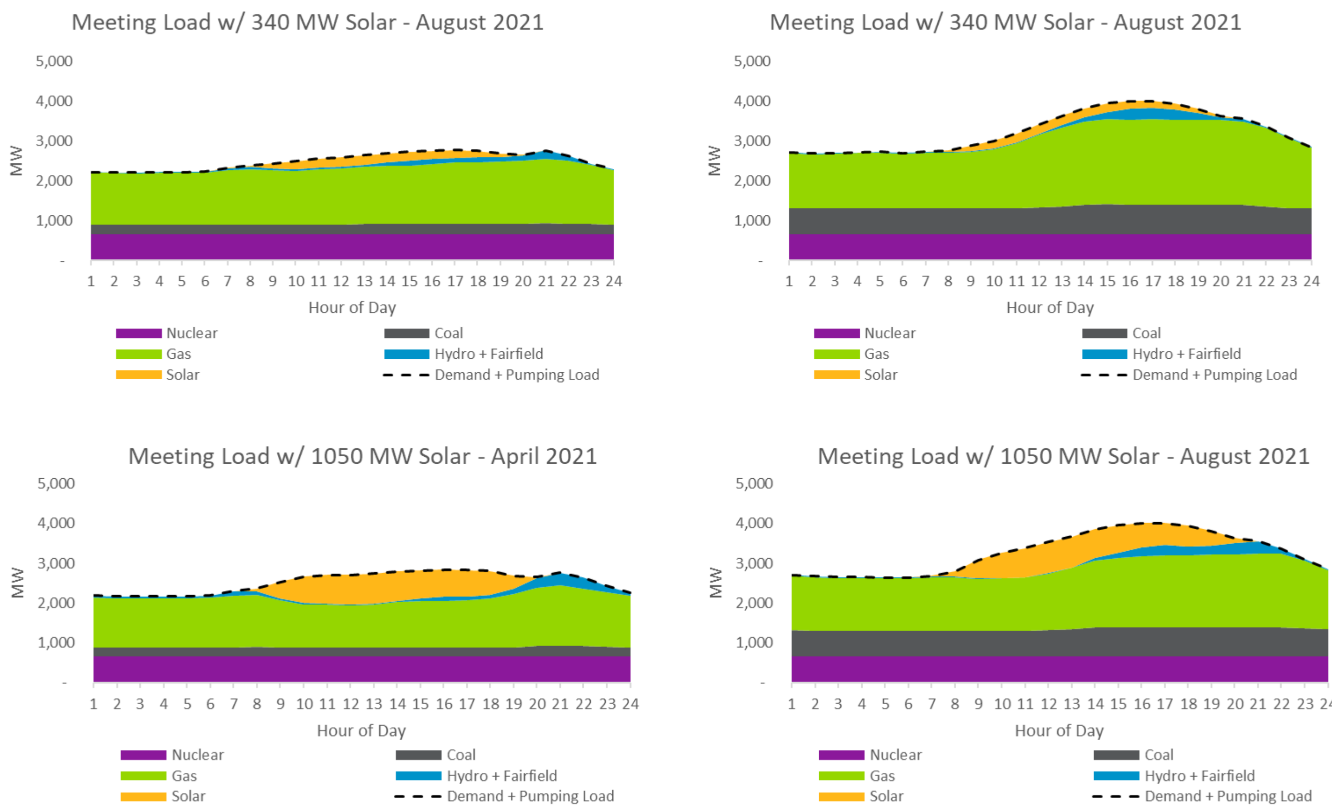
Compared to other power systems such as those in Florida or Duke Energy Carolinas, SCE&G has a high proportion of "baseload" generating capability from nuclear and coal plants. The key characteristic of baseload plants is that they have limited ability to change their generation quickly and are unable to start-up or shut-down without a long lead-time.

1.2 Changes to System Operation with Solar

As the amount of solar on the SCE&G system increases, the existing generators will be operated differently to ensure that load can be met and reliability criteria can be maintained. Power from solar generation rises in the morning, is at its peak throughout the day, and decreases when the sun sets. Furthermore, solar generation is intermittent meaning that solar generation is not fully controllable by SCE&G and can be either higher or lower than expected. To operate the system, other generators will need to be turned down in the middle of the day when solar generation is highest and sufficient reserves will need to be held so that SCE&G can maintain operation if solar generation is less than expected.

Some examples of how daily operation changes by season and as solar generation on the system increases are shown in Figure 2.

Figure 3. Average Daily Operation - Baseline and C2



Adding solar to SCE&G's system generally reduces the marginal cost of generating power as solar has no fuel costs associated with generation and adding it allows the SCE&G system operators to reduce the generation at other units. These direct impacts are calculated in the PR-1 and PR-2 avoided cost filings and show the benefits from solar to reduce fuel use and other operating costs.

However, SCE&G must also ensure that sufficient system reserves are available to replace generation when the actual solar generation is below the forecast. This would result in holding additional reserves on top of the 240 MW already required; SCE&G would have to change their system operation to ensure that these reserves can be met.

Depending on how the system is operating, there are several potential outcomes for SCE&G operation:

- There may already be sufficient online flexibility to meet the additional reserves in which case there would be no change to the operation.
- It may be necessary to generate more from less efficient resources to ensure that other units that can provide ramping capabilities are at less than full capacity.

- It may be necessary to start-up less efficient generation in order to be able to provide the reserves.

The costs to ensure this flexibility is what is estimated in this study and are separate from the system costs calculated in the PR-1 and PR-2 avoided cost filings.

The following two examples shows how system operation can change when additional reserves are required. With the current amount of reserves that SCE&G holds, the lowest cost way to operate the system is to have the CC units generate at almost full capacity while providing few reserves. Most of the system reserves are provided by Saluda Hydro and the CT gas units. When additional reserves are needed, the operators must turn down the CC units to provide reserves and turn up Steam Turbine (ST) Coal units to provide energy. This increases the cost to operate the system.

Figure 4. SCE&G Operation with Business-as-Usual Reserves Required

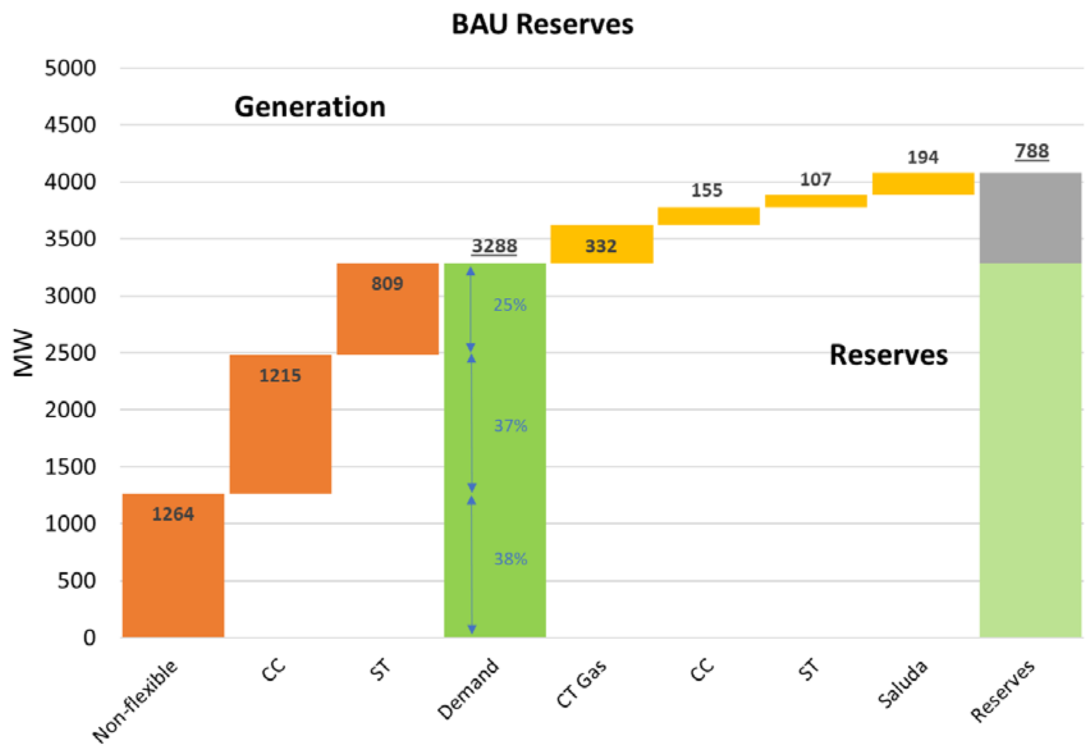
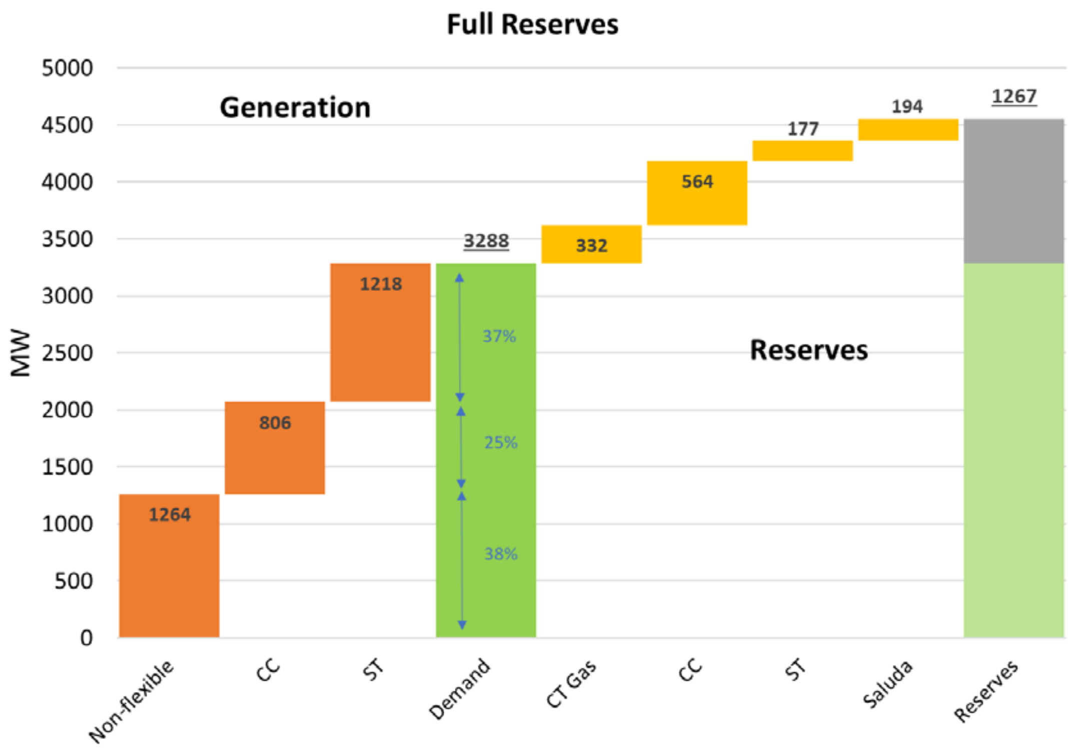


Figure 5. SCE&G Operation with Additional Reserves



2. STUDY METHODOLOGY

As discussed in Section 1, operating SCE&G's system with increasing solar installations will require the utility operators to maintain sufficient operating reserves and ensure that load can be served even when actual solar generation is less than expected generation. Mechanically, this means that SCE&G operators will need to maintain sufficient operating reserves (the ability to ramp units up) to both meet VACAR requirements and to cover any unexpected shortfall of solar generation.

The general approach to calculate the costs of this additional requirement is to simulate system operation with and without the additional operating reserves, compare system costs in the two scenarios, and evaluate if there are any other potential mitigation alternatives that could result in lowered system costs. The study forecasts system integration costs for 15 years from 2020 -2034. The following describes the full study methodology and assumptions in detail.

2.1 Key Study Assumptions

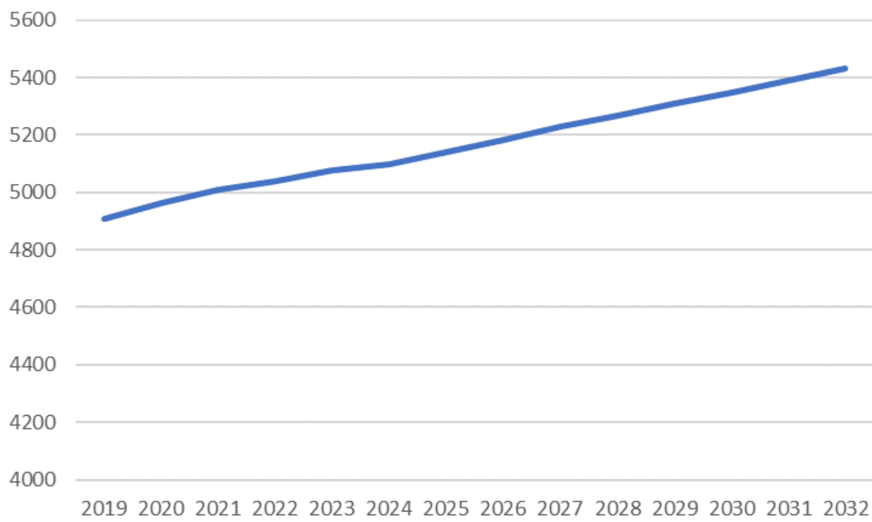
As a baseline, this study uses the same assumptions as SCE&G's Integrated Resource Plan (IRP). The key assumptions of the IRP include the forecasted system load and the existing and new resources needed to meet this load requirement.

2.1.1 System Load

The following chart shows the forecasted annual system peak load[5] for the study period of 2019 to 2032. Annual load grows at a constant and relatively low rate, with a CAGR of approximately 0.8% over the study period.

[5] The system was simulated hourly and the forecasted load is used on an hourly basis.

Figure 6. Annual SCE&G Peak Demand



2.1.2 SCE&G Generating Resources

Below is the list of SCE&G units. Solar units are not included as they vary between the cases analyzed by Navigant. The combined-cycles, ST Coal, ST Gas, and V.C. Summer nuclear plant provide the majority of baseload generation needed in SCE&G, with the ST Gas and CCs able to ramp up their output during peak hours. The CT Gas and Saluda plants are used for reserves and peaking needs.

Table 5. SCE&G Dispatchable Units

Plant	Units	Technology	Name Plate Capacity (MW)	Ramp Rate (MW/hr)	Quick Start	EFOR (%)	Start Cost ($)
Columbia Energy Center	1	CC	540	540	No	1.67	$17,534
Jasper	1	CC	920	190	No	2.4	$26,301
Urquhart CC	1 & 2	CC	450	450	No	0.9	$17,534
SCE&G Unnamed CC (2029 onward)	1	CC	520	127	No	2.4	$0
Coit	1 & 2	CT Gas	26	26	Yes	5	$0
Hagood	4	CT Gas	99	99	No	2	$0
Hagood	5 & 6	CT Gas	42	42	Yes	5	$0
Parr	1 & 3	CT Gas	73	73	Yes	5	$0
Urquhart CT	1 - 4	CT Gas	97	97	Yes	5	$0
Williams	1 & 2	CT Gas	52	52	Yes	5	$0
V.C. Summer	1	Nuclear	650	480	No	2	$0
Fairfield	1	Pumped Hydro	576	576	No	0	$0
Wateree	1 & 2	ST Coal	780	0	No	3.6	$15,286
Williams	1	ST Coal	615	0	No	4.3	$8,772
Cope	1	ST Coal	486	240	No	2	$4,299
Cope	1	ST Gas	420	240	No	1.1	$4,299
McMeekin	1 & 2	ST Gas	272	150	No	1	$2,923
Urquhart ST	3	ST Gas	104	60	No	12.2	$1,522
Saluda	5	Hydro	194	194	Yes	0	$0
Other Hydro Units*	-	Hydro	45	45	Yes	0	$0

Note: Hydro units are Neal Shoals, Parr Hydro, Saluda Hydro, and Steven's Creek

2.1.3 Solar Penetration Scenarios

Navigant ran three scenarios to analyze the impacts that various levels of solar would have on the SCE&G system. Each scenario included different amounts of utility-scale solar and is described below.

- Baseline Scenario – 336 MW of solar generation interconnected with SCE&G's system by the end of 2018.[6]
- Solar Case 1 – 637 MW of solar generation interconnected with SCE&G's system by the end of 2019.

[6] This is a conservative case. Actual installations by the end of 2018 already exceed this amount.

- Solar Case 2 – 1,044 MW of solar generation interconnected with SCE&G's system by the end of 2020.

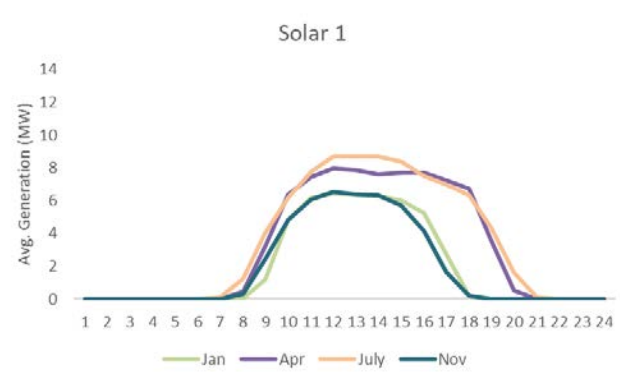
The maximum utility-scale solar nameplate facility rating for all three cases and the DER solar nameplate facility rating by year is shown in Table 6.

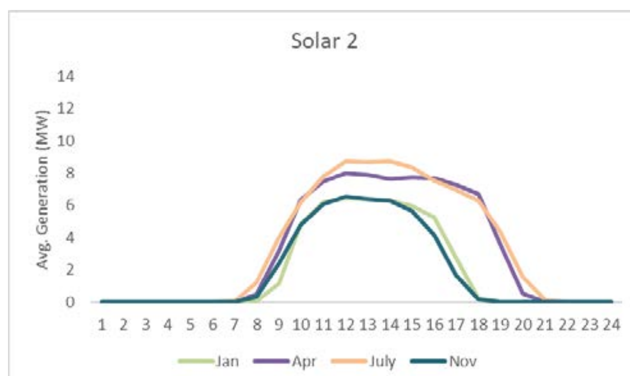
Table 6. Maximum SCE&G Solar Capacity

Solar	Maximum Nameplate Facility Rating (MW)				
	2019	2020	2021	2025	2030
Utility - Baseline	336	336	340	363	404
Utility - Solar Case 1	637	637	641	664	705
Utility - Solar Case 2		1,044	1,048	1,071	1,112

Navigant models all generation on an hourly basis; solar is modeled in PROMOD using a fixed 8760 hourly shape for generation. The 8760-shapes were based on historical hourly generation data provided by SCE&G. Figure 7 shows typical daily generation for two typical SCE&G solar plants,

Figure 7. Example Daily Solar Generation





2.2 Modeling the SCE&G System with PROMOD

Production cost models are a class of models that are used to complete analyses of electricity system costs. These models are appropriate for evaluating how system costs change when aspects of those systems change.

For this study, PROMOD was used. PROMOD is a widely licensed Production Cost Model used by many utilities and ISOs including PJM and MISO. There are other available Production Cost Models and consistent results can be expected if a different model was used for the study.

Like all production cost models, PROMOD simulates system operation hourly to minimize the total operating cost while ensuring that generation and load are matched and that operating reserve requirements are met. The model also takes into account generator operating limits and transmission constraints. The key outputs of the system simulation are the hourly details of system operation including generation by unit and the hourly operating costs.

From PROMOD, the production costs can be calculated by summing:

- Fuel costs
- Variable operating costs
- Start-up costs
- Emissions costs

In this study, SCE&G is modeled as a mostly isolated system without dynamic transmission connections to surrounding systems. This is appropriate for a planning study as it captures the requirement for SCE&G to maintain self-sufficiency in planning. As SCE&G does have the ability to contract for external power, emergency power imports were allowed at a cost of $300/MWh.

2.3 Forecasting Requirements to Integrate Solar

The necessary additional operating reserves that are needed with solar on the system are estimated using data sets providing by the National Renewable Energy Lab (NREL) specifically for solar integration studies.[7] These data sets provide forecasted and real-time solar generation data at sites across South Carolina. In the future, as SCE&G gains experience operating with solar generation, the solar uncertainty analysis can be updated with actual operating data rather than the data provided by NREL.

The operating reserve requirements from solar are driven by the level of forecast uncertainty in solar generation. The NREL dataset provides the 4 hour-ahead forecast of hourly solar generation. This is the forecast that SCE&G system operators would use to schedule their units and determine which generators are required to be line. The forecasted solar is compared to the real-time solar generation dataset to calculate the generation variance from the forecast. SCE&G needs to hold sufficient reserves to be able to respond to the worst-case downward variance of solar generation while maintain their reserve requirements.

An outcome of the solar uncertainty analysis, described in more detail in Section 3, is that the level of solar generation uncertainty depends on the level of solar generation. The amount of reserves that need to be held by SCE&G for variable integration depend on the level of forecasted solar generation. This

[7] https://www.nrel.gov/grid/solar-integration-data.html

dynamic is incorporated into the study analysis by blending the production costs of several cases operating the system with different levels of operating reserves to account for the day-to-day variability in the overall requirements.

2.4 Estimating Integration Costs

To calculate the integration costs of the various mitigation options, PROMOD was run with different levels of operating reserves calculated as a mitigation option and the production costs were compared to the Business as Usual scenario, which is the PROMOD scenario benchmarked to the actual SCE&G system operation.

The study includes a comparison of the system costs as operating reserves increase to handle solar uncertainty. These costs are compared for each of the three solar penetration scenarios and up to four different levels of operating reserves. Table 7 shows the full set of study scenarios. The BAU reserves are the 240MW currently required. The other reserve levels are those required for the uncertainty associated with the varying levels of solar penetration.

Table 7. Solar and Reserve Scenarios

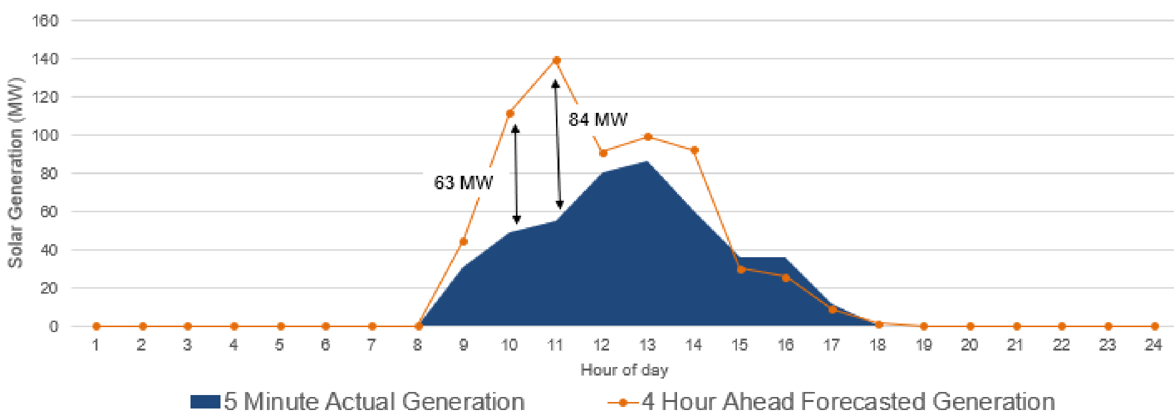
Baseline Solar (~350 MW)	SC1 Solar (~725 MW)	SC2 Solar (~1050 MW)
BAU Reserves	BAU Reserves	BAU Reserves
Baseline Reserves	Baseline Reserves	Baseline Reserves
	C1 Reserves	C1 Reserves
		C2 Reserves

Beyond simply holding additional reserves with the current power system, SCE&G has the ability to add new resources such as CT gas or storage that can provide reserves. If new units are added as a mitigation option, then new resources are added to the set that is available to SCE&G to meet load and reserve requirements. The capital costs of the new resources would be added to the total mitigation costs for comparing between the BAU and change scenarios. The study tests whether additional resources can be used to reduce the total integration costs.

3. SOLAR GENERATION VARIABILITY IN SCE&G SERVICE TERRITORY

Solar generation is intermittent, meaning that actual operation cannot be perfectly forecasted and there is nearly continuous variation in generation that must be reacted to by SCE&G operators. The following chart shows the difference between a 4-hour ahead forecast and actual 5-minute operation of solar in South Carolina. The forecasted generation varies by as much as 84 MW for a single hour which could be an issue in maintaining system reliability for SCE&G and would require adequate reserves that can be called in to maintain supply and demand balance in the region. The chart below captures total solar generation at four different locations in the system to provide a system-wide variability whereas variability at a single solar site can be much higher in terms of percentage of solar generation shortfall.

Figure 8. Solar Generation Variability Example



3.1 Data Sources

The amount of solar variability that SCE&G operators will need to be able to respond to is driven by the level of forecast uncertainty for solar generation in the territory. The challenge is that there is a very short track record in the system for how much solar uncertainty there is. SCE&G does not have data that can be used to calculate the distribution of the difference between solar generation forecasts and the actual solar generation.

To be able to complete the study, Navigant used two sources of solar data:

- The hourly shape for solar generation that is inputted into PROMOD is developed from an aggregation of real solar generation hourly shapes from SCE&G.

- The forecast uncertainty is developed from the National Renewable Energy Lab's (NREL) Solar Integration Dataset.[8] This is a public dataset that provides both forecasted and real-time solar generation at a large number of sites around the U.S.

3.2 Detailed Approach

The solar forecast error is calculated as the difference between the 4-hour ahead forecast generation and the 5-minute actual solar generation. This is appropriate because as the solar generation changes in the period between the 4-hour ahead forecast and actual operation, SCE&G will not have sufficient time to turn on any additional CC or ST units. The only reserves that are available are the additional generating capacity, or headroom, for Fairfield, Saluda, the CTs, and the CCs and STs that are already online.

The following methodology is used to calculate the solar forecast error.

1. Calculate the 4-hour ahead solar forecast as the average of 4 potential solar sites located around the SCE&G service territory.
2. Calculate the 5-minute actual generation as the average of the actual generation at the same 4 sites.
3. Calculate the 5-minute variance in solar generation as the difference between the forecast and the actual in every 5-minute period.
4. Calculate the solar variance the SCE&G must respond to as the 15-minute moving average of the 5-minute forecast error.[9]

The result of this analysis is a comprehensive set of data that gives the amount that solar generation varied from the forecast. This can be evaluated by season and time period to determine how operators would need to plan for solar uncertainty.

3.3 Solar Generation Variability Results

SCE&G's operators need visibility on the levels of solar at risk of not showing up given the forecasted solar. To maintain reliability, it is necessary to have sufficient reserves to replace the missing solar generation under the worst-case scenario. The difficulty for operating the system is that SCE&G not only does not know when solar will generate less than forecasted but also does not want to overestimate the uncertainty and then hold more reserves than needed, which would increase costs. The uncertainty that needs to be estimated is the likelihood and worst case for solar generating less than forecasted given the amount of solar that is expected to be on the system.

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[8] https://www.nrel.gov/grid/solar-integration-data.html

[9] SCE&G must meet NERC Reliability Based Control Standards which give the utility up to 30 minutes to respond to any large deviation between load and generation. 15 minutes is chosen for this study as SCE&G would want to respond well before 30 minutes to ensure sufficient time to avoid exceeding the 30-minute limit.

One outcome of this analysis is that the level of solar variability depends the amount of solar that is generating. At a high level, the higher the percentage of the total installed nameplate facility rating of solar that is generating, the lower the proportion of generation that is at risk.

Table 8 shows the full results of this analysis. The rows give the forecasted solar generation as a percentage of the installed nameplate facility rating. The columns give the percentage drop in solar generation. The cells give the conditional probability of a given drop in solar generation given the level of forecasted generation.

For example, if 1000 MW of solar was installed on the system and it was forecasted to generate 400 MW, the highlighted cells show:

- There is a 1% chance of a 75% drop – equivalent to 300 MW of solar not showing up (only 100 MW is generated).
- There is a 9% chance of a 25% drop- equivalent to 100 MW of solar not showing up (only 300 MW is generated)

Table 8. Conditional Probability of Solar Variability

Forecasted Generation	>75% Drop	>65% Drop	>55% Drop	>45% Drop	>35% Drop	>25% Drop	>15% Drop	>5% Drop
20%	0%	1%	4%	6%	9%	16%	23%	33%
25%	1%	2%	4%	5%	8%	13%	21%	33%
30%	1%	2%	3%	6%	9%	13%	22%	34%
35%	1%	2%	4%	7%	11%	16%	22%	33%
40%	1%	1%	2%	3%	5%	9%	16%	27%
45%	0%	1%	1%	2%	4%	8%	13%	22%
50%	0%	1%	1%	2%	4%	7%	12%	25%
55%	0%	0%	0%	1%	1%	2%	6%	16%
60%	0%	0%	0%	0%	0%	1%	3%	11%
65%	0%	0%	0%	0%	0%	1%	3%	5%
70%	0%	0%	0%	0%	0%	0%	2%	5%

Since SCE&G must maintain self-sufficiency, it is necessary to plan for the worst case drops in solar generation. Table 9 gives the solar generation at risk that is used in this study. In each hour, the amount of solar forecasted to generate is calculated and this table is used to calculate the potential drop in solar that the system may need to respond to.

Table 9. Solar Forecast Uncertainty

Expected Generation as % of Installed Nameplate Facility Rating	Maximum Drop in Generation
< 40%	75%
40% - 50%	65%
50% - 55%	45%
> 55%	25%

3.4 Geographic Diversity

An important part of this analysis is to consider geographic diversity when forecasting the solar uncertainty. Even in a service territory as geographically compact as SCE&G's, spreading solar generation geographically can reduce the uncertainty.

Without considering geographic diversity, the solar uncertainty would be much higher. To avoid this, the forecast error analysis was completing using NREL data located at four points around the SCE&G territory chosen to be near load centers. Averaging the forecast error among multiple locations properly accounts for the expected geographic diversity of solar resources being added to the system. This ensures that the analysis is not too aggressive in estimating the additional reserves needed by SCE&G.

The table gives an example of the expected probability of losing solar generation when operating at 50% of maximum generation for the average of the four NREL points used, and for a single NREL point located near Columbia. The key result is that the uncertainty is significantly higher when estimated at a single point.

Table 10. Impact of Geographical Diversity on Solar Uncertainty

NREL Location	Forecasted Generation	>75% Drop	>65% Drop	>55% Drop	>45% Drop	>35% Drop	>25% Drop	>15% Drop	>5% Drop
SCE&G Avg.	**50%**	0.1%	0.6%	1.1%	2.1%	3.4%	7.4%	12.9%	21.8%
Columbia, SC	**50%**	3.2%	4.2%	5.2%	7.3%	10.8%	14.7%	21.3%	35.4%

4. DEMONSTRATING THE NEED FOR ADDITIONAL RESERVES

SCE&G reliability is threatened when there is insufficient system ramping capability to meet potential drops in solar generation while maintaining the required reserves.

4.1 Reliability Challenges without Adding Reserves for Variable Integration

In each hour of the forecast, the following process is used to calculate whether SCE&G has any reliability issues from solar generation that need to be mitigated.

1. Calculate the total amount of ramping capability on the system.
   – This is the sum of the ramping up capability of online units and the capacity of quick start units that can be turned on.
   – This will be at least the total reserve requirement (240 MW) but is typically more depending on how the system is operating.
2. Calculate the potential lost solar generation due to forecast uncertainty.
3. Subtract the lost solar generation from the system ramping capability.
4. Flag any hours in which the minimum reserve requirement is not met as reliability violations.

The table below shows 3 hours in which there are reserve shortfalls if the system only requires 240 MW reserves but includes risk of solar generation being out. These sample hours are the reason that SCE&G operators must hold more reserves for the solar uncertainty.

Table 11. Example of Hours with Reserve Shortages

Hour	Load	CC Ramp (Gen)	CT Ramp (Gen)	Saluda Ramp (Gen)	Fairfield Ramp (Gen)	Interruptible Load for reserves	Total Reserves Online	Risk of Solar Out	Reserves Shortage after Solar
4/14/21, 3pm	3558MW	55MW (1548MW)	162MW (227MW)	31MW (163MW)	0MW (0MW)	100MW	347MW	191MW	84MW
9/16/24, 3PM	4196MW	72MW (991MW)	158MW (174MW)	185MW (9MW)	0MW (576MW)	100MW	622MW	432MW	50MW
8/1/25, 4PM	4721MW	0MW (1778MW)	204MW (128MW)	10MW (184MW)	432MW (144MW)	100MW	458MW	286MW	68MW

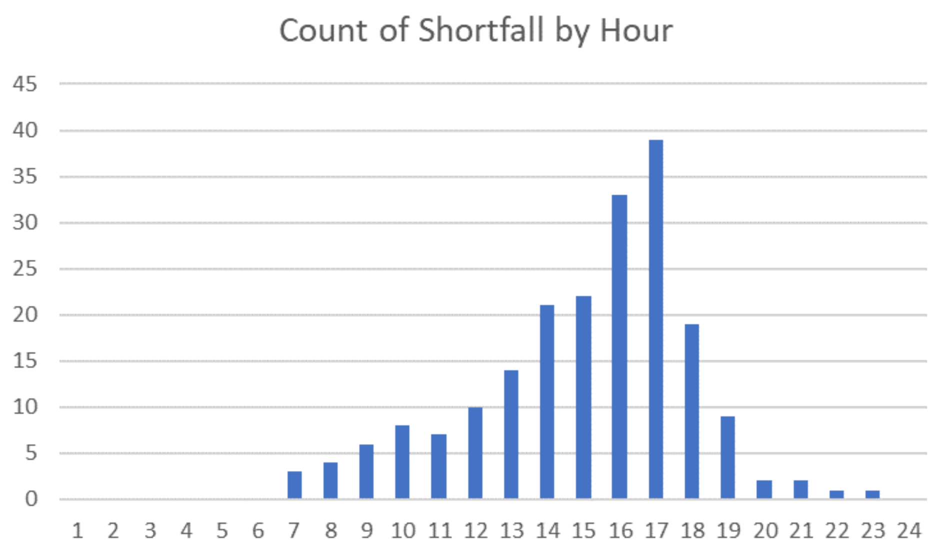
While in most hours there are more than the minimum reserves, there are a material number of hours in each scenario for which additional reserves would need to be held for the solar generation.

PROMOD was used to simulate the system operation in each solar penetration scenario and the number of hours in the forecast period in which SCE&G was not holding sufficient reserves to account for solar uncertainty was calculated. In each of these scenarios, the hours with insufficient reserves occurred in all seasons across the year.

- Baseline scenario – 74 hours
- Solar Case 1 – 102 hours
- Solar Case 2 – 196 hours

Figure 9 shows the distribution by hour of the reserve shortfalls. These hours are concentrated during the evening when solar is ramping down.

Figure 9. Reserve Shortfalls by Hour in SC2



4.2 Calculating the Additional Reserve Requirements

The analysis in Section 4.1 demonstrates that if SCE&G does not hold additional reserves then there will be a significant number of hours in which reliability violations occur. That analysis does not show the amount of additional reserves that must be held.

When planning operation, SCE&G only knows the forecast for solar generation and must plan for the worst case. This means that the utility must hold sufficient reserves in each case to be able to respond to the worst case drop in solar given the forecast.

For each solar penetration scenario, the maximum expected drop in solar generation for each year was used to determine the extra operating reserves that need to be held to ensure that the reserve requirements are met. The reserve requirement changes by year rather than month because the maximum in each month is nearly constant.

Table 12 shows the maximum additional reserves needed in each solar penetration scenario plus the BAU level of reserves held by SCE&G.

Table 12. Maximum Additional Reserves Needed

Year	BAU	Baseline	SC1	SC2
2019	240	347	421	420
2020	240	348	445	529
2021	240	349	447	579
2022	240	351	448	581
2023	240	352	450	582
2024	240	354	451	584
2025	240	356	453	586
2026	240	358	456	588
2027	240	360	458	590
2028	240	363	460	593
2029	240	365	463	595
2030	240	368	466	598
2031	240	371	469	601
2032	240	375	472	605

One aspect of holding reserves is that SCE&G knows the level of expected solar generation prior to setting the reserves to be held, so the required reserves needed to compensate for a potential drop in solar would be adjusted on a daily or hourly basis.

Table 12 shows the maximum needed reserves necessary, but when calculating the costs, it is important to consider that many individual days within each case have lower forecasted solar than the maximum and hence need fewer reserves.

For SC2, the analysis shows:

- SC2 level of reserves is needed for 38% of the days
- SC1 level of reserves is needed for 51% of the days
- Baseline level of reserves is needed for 12% of the days

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Cost of Variable Integration

To ensure that the analysis does not overestimate the costs to integrate the SC2 reserves, PROMOD was run with each of these levels of reserves and then the results were blended using the weighted average of costs tied to the number of days that each level of reserves was required.

5. MITIGATION OPTIONS AND INTEGRATION COSTS

5.1 Potential Mitigation Options

The mitigation needed to integrate solar generation is to hold additional reserves that will be available if actual solar generation is less than forecasted. There are two broad mechanisms for SCE&G to do this:

1. Operate the existing system differently so that there are more operating reserves.
2. Procure quick-start resources such as battery storage or CT gas units that will be able to provide reserves even when offline.[10]

In this analysis, the cost of holding additional reserves is calculated first. This is then compared to the cost of adding new resources to check whether there is a lower cost approach to procuring the needed reserves. The integration cost for the solar resources is the levelized cost difference of the system costs with and without additional reserves.

5.2 System Impacts of Holding Additional Reserves

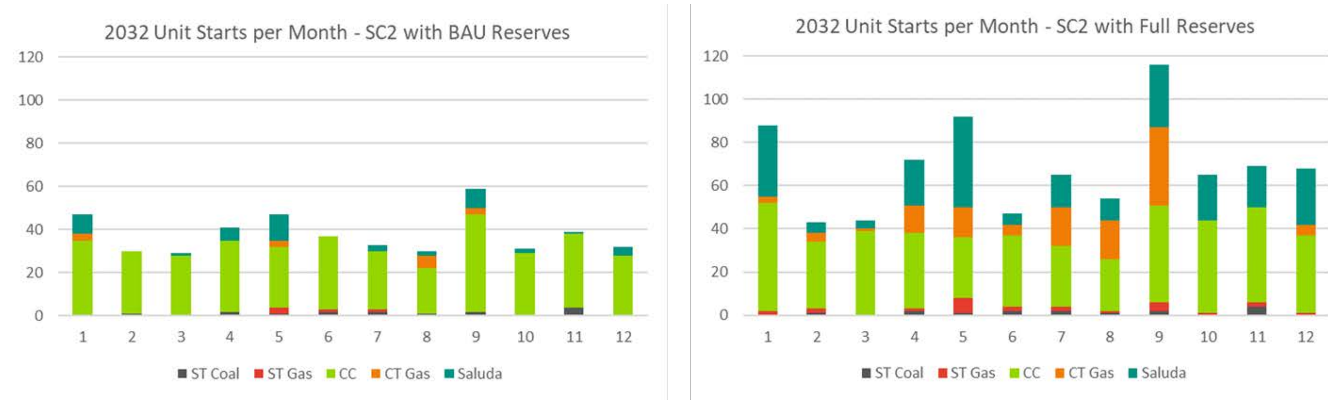
In most hours, especially overnight, SCE&G holds more than the minimum necessary reserves through their least-cost security constrained operation. This means that adding to the reserve requirement in the simulation does not materially influence the system operation in those hours. However, in hours in which SCE&G holds the minimum or close to the minimum amount of reserves, some resource generation levels will have to be changed.

PROMOD solves for the least-cost dispatch while respecting the additional reserve requirements. To a large extent, additional reserves come from reducing the generation from CC units so that they are providing more flexibility. ST units are turned on to ensure that load can be met. Figure 10 shows the comparison of the starts per month in case SC2 with and without additional reserves being held. As would be expected, the cycling increases with the additional reserves as the CTs and STs must turn on to be available.[11]

[10] Note that there are methods for solar units to provide flexibility and ramping to the system. Although this may be a feasible alternative in the future, this possibility has not been considered in this analysis because SCE&G cannot implement it unilaterally but only with technological changes by the solar facility owners.

[11] Note that Saluda is allowed to cycle more in the alternate case than according to the current operating agreement. This is a **conservative** assumption. If Saluda were more limited as per the current operating agreement, then other units would have to make up the difference and integration costs would increase.

Figure 10. Comparison of Unit Cycling



To a large extent, the driver of the integration costs are increased fuel and operating costs. This is because less efficient units must be online to provide energy, units must operate at less efficient power levels, and there are increased start-up costs due to additional cycling.

One point of conservatism in this analysis is that there are additional maintenance and fuel costs from ramping generating resources up and down very quickly when renewable generation varies. This analysis only considered the costs to maintain reserves and excluded the costs from the additional stress and reduced efficiency from matching solar generation short-term variability.

5.3 Cost of Holding Additional Reserves without Other Changes

As described, the cost of holding additional reserves is calculated by comparing the PROMOD production costs with and without holding additional reserves required to meet solar uncertainty.

One concern is to ensure that there is no double counting with the costs reported in the PR-1 and PR-2 avoided cost study. In that study, there are increased costs from Energy Not Served and Reserve Deficits. A side-benefit of holding additional reserves for variable integration is that both Energy Not Served and Reserve Deficits would likely be decreased. Conservatively, for this study, the entire cost of Energy Not Served ($0.682/MWh) and the entire cost of Reserve Deficits ($0.284/MWh) ($0.97/MWh rounded total) are assumed to be eliminated with the extra reserves needed for solar.

The comparison of system production costs in the three solar penetration scenarios are given in Table 13. The Net Present Values (NPV) are calculated over a 15-year period (2020 – 2034) using SCE&G's discount rate of 7.9%. The results show that the costs increase relatively linearly between the 3 cases as more solar is added to the system resulting in a variable integration cost between $3.52/MWh and $4.04/MWh. The total incremental system costs in SC2 is approximately $73.2M.

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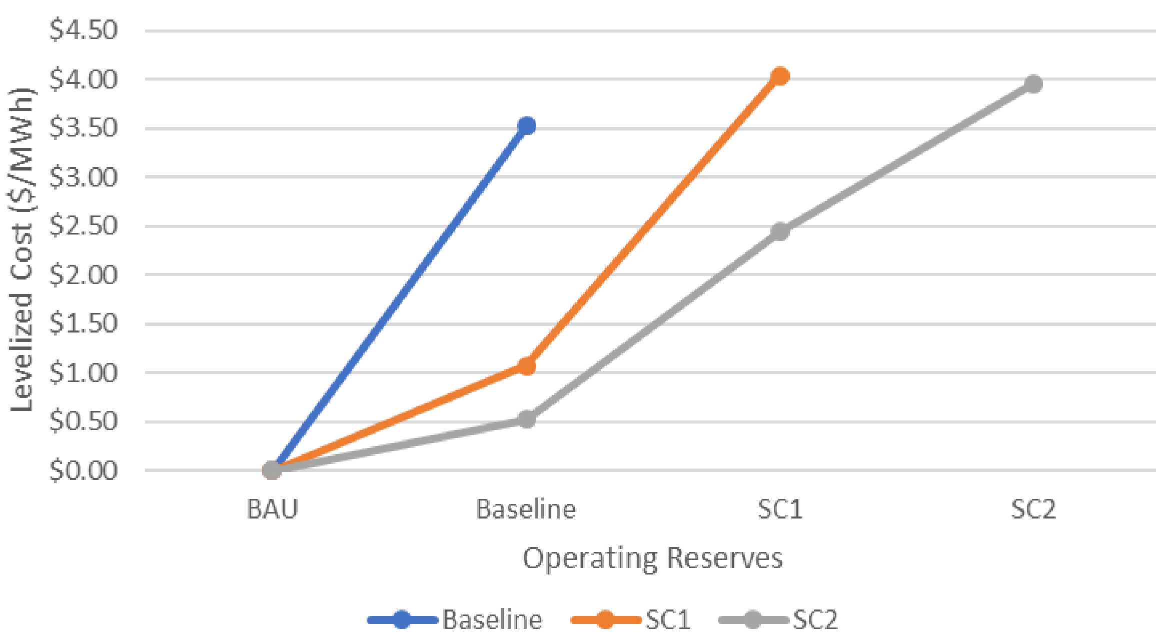
Cost of Variable Integration

Table 13. Cost to Integrate Variable Generation

	Baseline	SC1	SC2
Cost Difference NPV (2020 $)	$21,441,812	$46,878,790	$73,242,219
Solar Generation NPV (MWh)	6,091,424	11,603,661	18,495,510
Levelized Cost (2020 $/MWh)	$3.52	$4.04	$3.96

Figure 11 shows the incremental levelized cost as reserves are added in each scenario. For example, in SC2, the results show that integration cost are approximately $0.50/MWh if only the baseline solar reserves are needed. These costs increase to $4.02/MWh when all of the reserves required for the SC2 case are required. The expectation is that as solar continues to be added to the system and additional reserves continue to be needed that these costs would increase.

Figure 11. Levelized Costs as Reserves are Added



The breakdown of the cost drivers in SC2 are shown in Table 14. The majority of costs are from additional fuel cost costs but VOM and start-up costs are also material increases in system costs.

Table 14. Breakdown of Incremental Costs in SC2

	VOM	Fuel	Emission	Start-up	Total
Cost Difference NPV ($)	$13,941,615	$40,320,211	$48,760	$19,103,954	$73,242,219
Generation NPV (MWh)			18,495,510		
Levelized Cost ($/MWh)	$0.75	$2.18	$0.003	$1.03	$3.96
% of Total Cost	19%	55%	0%	26%	100%

5.4 Screening the Potential to Mitigate with Additional Resources

In SC2, the NPV of the cost of holding additional reserves for variable integration is $73.2M driven by the need for additional reserves of approximately 350MW.

If SCE&G can add resources that can provide these reserves for less than incremental cost, then it would be possible to reduce the overall integration costs of solar to the system.[12] For providing reserves, the best options are quick-start gas CTs or battery storage. This study considered the following resources and costs:

- Quick-start CT - $700/kW overnight cost
- 1-hour Lithium-Ion Battery - $800/kW overnight cost[13]
- 2-hour Lithium-Ion Battery - $1000/kW overnight cost

At a high level, this implies that SCE&G could add approximately 110 MW of quick-start CT, approximately 95 MW of 1-hour battery, or approximately 75 MW of 2-hour battery. None of these capacities would be sufficient to meet the additional reserve requirements of the solar generation.[14]

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[12] Note that if solar units were operated to provide flexibility to the system, the integration costs borne by SCE&G would be reduced.

[13] Note that this cost assumes technology improvement and cost declines through 2025

[14] To do a full analysis of mitigation with additional resources it would be necessary to also calculate additional benefits and costs associated with owning and operating these resources. The current analysis is only a screening to demonstrate that the additional of these resources is not able to reduce the overall integration costs.

APPENDIX A. MARKET MODELING PROCESS

Navigant's market modeling approach relies on a multifaceted approach for modeling and simulating the energy market and studying the performance of energy assets in the marketplace. Navigant's approach relies on the involvement of numerous subject matter experts with specific knowledge and understanding of several fundamental assumptions, such as fuel pricing, generation development, transmission infrastructure expansion, asset operation, environmental regulations, and technology deployment. From our involvement in the industry, Navigant has specific and independent views on many of these fundamental assumptions based on our knowledge and understanding of the issues. Provided below is an overview of the modeling process.

A.1 Electric Market Simulation

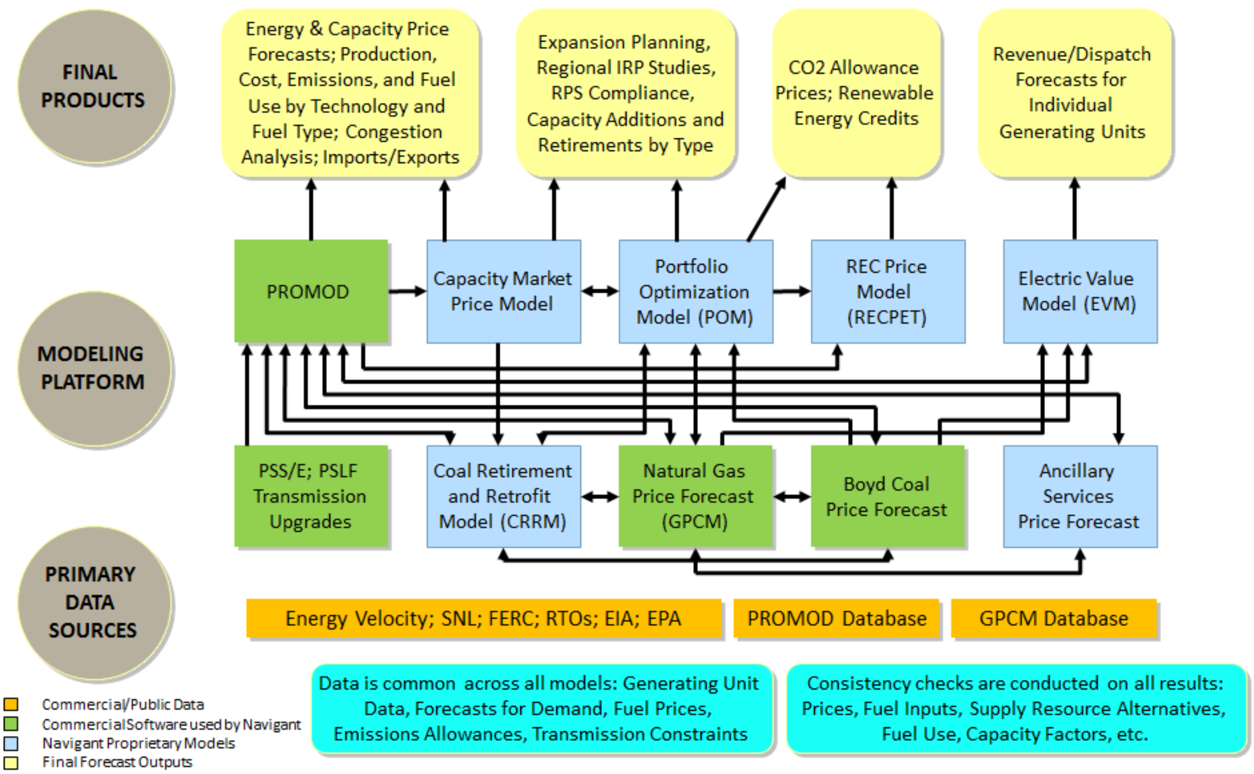
A diagram depicting the models used in Navigant's market modeling can be seen in Figure A-1. Navigant's proprietary Portfolio Optimization Model (POM) is a linear optimization model used for capacity expansion. POM simulates economic investment decisions and power plant dispatch on a zonal basis subject to capital costs, reserve margin planning requirements, RPS, fuel costs, fixed and variable operations and maintenance costs, emissions allowance costs, and zonal transmission interface limits. This model incorporates the same generation base, demand forecasts, fuel prices, other operating costs, and plant parameters that are utilized throughout the market simulation modeling process. The model simultaneously performs least-cost optimization of the electric power system expansion and dispatch in multi-decade time horizons. POM can perform multivariate optimization, which can consider value propositions other than cost minimization, such as sustainability, technological innovation, or impacts on other sectors, such as natural gas. The generation expansion results from POM are used in the fundamental energy price forecast.

Navigant uses PROMOD, a commercially-available software, to develop its wholesale energy market price and plant performance forecasts. PROMOD is a detailed energy production cost model that simulates hourly chronological operation of generation and transmission resources on a nodal basis in wholesale electric markets. PROMOD dispatches generating resources to match hourly electricity demand, dispatching the least expensive generation first. The choice of generation is determined by the generator's total variable cost given operating constraints such as ramp rates (for fossil resources) or water availability (for hydraulic resources), and transmission constraints. The total variable cost of the marginally dispatched unit in each hour sets the hourly market clearing price. All generators in the same market area that are selected to run receive the same hourly market clearing price adjusted for losses and congestion, regardless of their actual costs. The LMP's produced by PROMOD compose Navigant's structural market price forecasts. Navigant does not employ bid-adders or other exogenous adjustments to prices in the PROMOD forecast.

Within PROMOD, production costs are calculated based upon heat rate, fuel cost, and other operating costs, expressed as a function of output. Physical operating limits related to expected maintenance and forced outage, start-up, unit ramping, minimum up time and downtime, and other characteristics are factored into the simulation. Supply offer prices are simulated for each unit within PROMOD that correspond to the minimum price the unit owner is willing to accept to operate the unit. For most generation resources, offer prices are composed primarily of incremental production costs. Incremental production cost is calculated as each unit's fuel price multiplied by the incremental heat rate, plus variable operations, emissions, and variable maintenance costs.

Where relevant (primarily for thermal units), the unit offer price also incorporates the unit's start-up and no-load costs. The start cost component includes fuel costs and other operating costs encountered in starting the generating unit, beyond those reflected in the heat rate and variable operating cost assumptions. The no-load cost reflects the difference between average and incremental fuel costs for generating stations that are dispatched at less than full output.

Figure A-1. Navigant's Market Simulation Modeling Process



Source: Navigant

PROMOD has several distinguishing features that qualify it for application in electric power forecasting and related studies. These features include the following:

- Individual transmission line modeling
- Detailed and flexible unit commitment and dispatch modeling
- Modeling of operational transmission constraints (e.g., operating nomograms)
- Calculation of security-constrained dispatch schedules
- Hourly modeling of loads and resource operation

When preparing market price forecasts, Navigant first forecasts a fundamental, or structural, hourly energy price series for the applicable node or zone using PROMOD. Structural prices represent expected day-ahead market clearing prices under conditions of perfect foresight about load, generator and transmission availability, and fuel costs. As such, they lack information about additional price volatility in the market that can stem from intra-month volatility in fuel and emissions prices, stochastic variations in demand, and deviations of market bidding away from marginal cost bidding. In order to account for this missing volatility and any model error, Navigant incorporates adjustment factors to correlate power price volatility from simulated ex post “backcasts” in PROMOD with historical volatility experienced in the market. Using benchmarks derived from historical data for a rolling three-year period, the PROMOD hourly price forecasts are adjusted to account for the relative difference between actual market prices and PROMOD’s (simulated) prices by season and time period. The actual prices and the simulated prices are grouped and averaged in 18 time blocks differentiated by season (summer, winter, shoulder) and time-of-day (4 hour blocks corresponding to off-peak and peak periods). After eliminating historical price spikes deemed to be unpredictable (two standard deviations outside the time-block average), time-block ratios of actual prices to simulated prices are used to adjust the PROMOD forecast, and these are the final adjusted market prices provided in this report.

Navigant also uses GPCM to develop our Reference Case Gas Price Forecast. GPCM is a commercial linear-programming model of the North American gas marketplace and infrastructure. Navigant applies its own analysis to provide macroeconomic outlook and natural gas supply and demand data for the model, including infrastructure additions and configurations, and its own supply and demand elasticity assumptions. Forecasts are based upon the breadth of Navigant’s view, insight, and detailed knowledge of the US and Canadian natural gas markets. Adjustments are made to the model to reflect accurate infrastructure operating capability and the rapidly changing market environment regarding economic growth rates, energy prices, gas production growth levels, demand by sector and natural gas pipeline, storage, and LNG terminal system additions and expansions. To capture current expectations for the gas market, this long-term monthly forecast is combined with near-term New York Mercantile Exchange average forward prices for the first two years of the forecast.